BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY in the 2001 Annual Transition Cost Proceeding for the Record Period July 1, 2000, through June 30, 2001. (U 39 E)	Application No. 01-09-003

DIRECT TESTIMONY AND EXHIBITS OF DOUGLAS C. SMITH

EXECUTIVE SUMMARY

This testimony assesses the reasonableness of Pacific Gas and Electric Company's ("PG&E") power procurement, and specifically assesses PG&E's hedging strategy and practices for the record period July 1, 2000 through June 30, 2001, focusing on the amounts and timing of purchases in the California Power Exchange ("PX") Block-Forward Market ("BFM") for delivery in peak hours. The quantification of the costs and benefits associated with PG&E's strategy, and with the alternate described herein, end December 31, 2000, shortly before PG&E ceased its role as the buyer of the net short because of credit limitations. PG&E incurred an additional $434 million to buy electricity during the July to December 2000 peak period as a result of its failure to develop and execute a reasonable hedging strategy. This estimate represents the difference between starting to hedge sooner rather than later and using a hedge ratio of 80 percent rather than **(REDACTED)** under PG&E's program. In the simplest terms, PG&E did half of the job it needed to do.

Based on the analysis summarized below, the testimony demonstrates the following primary conclusions:

- PG&E did not pursue a reasonable BFM purchase strategy. Despite working with the PX to develop a market for block-forward contracts, and seeking and receiving Commission authority to participate in that market up to its net short position, PG&E did not develop a BFM strategy for the record period that made proper use of that authority.

- PG&E's failure to develop a reasonable BFM strategy is attributable in part to the fact that it did not act on market information it possessed that provided ample evidence of an elevated probability of price risk.

- PG&E's arguments as to why it chose to hedge substantially below the limits established by the Commission are not convincing. PG&E had a large net short position for the record period. In late 1999 and early 2000, when PG&E had authorization to make BFM purchases, the available information about the Western market indicated that spot market prices were likely to increase in 2000, and that there was a meaningful probability of large increases. It was a logical time for power buyers to be hedging. This is particularly true for PG&E since it faced a fixed retail rate cap.

- A review of PG&E's power purchases for the record period shows that after receiving authority in July 1999 to make BFM purchase to hedge the cost of its net short position, PG&E did not make any BFM purchases for the record period until **(REDACTED)**. As a result, only a **(REDACTED)** of PG&E's net short position was purchased before **(REDACTED)**, and prudently protected against the large market price increases that followed. Most of PG&E's purchases for delivery in the record period were made in **(REDACTED)** or later, after market prices had increased greatly. In short, while PG&E had access to standard tools (i.e., BFM purchases) that would have provided a great deal of protection against potential market price increases, it chose not to fully utilize those tools and paid the price when it found itself exposed to the Western power crisis that followed.

- Based on the information readily available at the time, PG&E should have begun to hedge its exposure to spot market prices earlier than it did and should have purchased a larger fraction of its net short position on a forward basis. Specifically, it would have been prudent, based on the information readily known to PG&E management, for PG&E to promptly begin to utilize the BFM purchasing authority of approximately 2,000 MW that the Commission granted it in July 1999. After the Commission increased PG&E's BFM purchasing limits (to the full net short position) in March 2000, it would have been prudent for PG&E to utilize most or all of that authority in a sequential fashion over the subsequent months.

- If PG&E had implemented such a strategy, its power purchase costs for the period July through December 2000 would have been about $434 million lower than actual.

- PG&E relies upon concerns over BFM cost recovery to explain its decision to hedge below the regulatory limit. These claims are general and do not withstand scrutiny. PG&E appears to have been too concerned about regulatory events, while giving too little weight to potential market events.

The testimony recommends that the California Public Utilities Commission ("Commission"): (i) find PG&E imprudent for not pursuing a reasonable BFM purchase strategy; and (ii) direct PG&E to debit $434 million from its entries to the Transition Cost Balancing Account in accordance with the alternate hedging strategy described below.

From the opening of the PX market on April 1, 1998 until July 1999, PG&E relied on purchases of spot market energy through the PX day-ahead and hour-ahead markets and the California Independent System Operator's imbalance market ("CaISO") to supply its energy needs not otherwise supplied by its remaining self-owned generation and power purchase contracts (i.e., the net short position). However, because the prices paid for energy purchased through the PX and CaISO were dependent on the balance of supply and demand and various input prices (e.g., natural gas prices and nitrogen oxide ("NOx") emission allowance prices), PG&E's power purchase costs could vary significantly if that balance was disturbed or input prices changed. In theory, as long as there was a reasonable excess of power supply bid into the spot market, and input prices did not change appreciably, competition between power suppliers would keep spot market prices in check.

Hedging programs, commonly used by businesses to protect against variance in future costs and revenues, provide buyers such as PG&E with the ability to reduce the uncertainty of their power supply costs by securing a portion of the supply in advance at known prices. In July 1999, the Commission approved PG&E's request to participate in the PX's new BFM. The BFM offered PG&E an opportunity to reduce its substantial exposure to spot market prices by locking in supplies in advance at fixed prices.

Although the Commission initially limited the amounts that PG&E could purchase in the BFM and the duration of those purchases, the July 1999 decision was nonetheless important for PG&E because retail rates had been frozen as part of the industry restructuring. This meant that power costs in excess of that allowed for in retail rates would not automatically be recovered from customers. In early 2000, PG&E returned to the Commission and requested expanded BFM purchasing authority in order to increase its opportunity to hedge price risks. In March, 2000, the Commission granted PG&E's request and authorized it to purchase up to its net short position and extended the delivery deadline until the end of PG&E's rate freeze. Finally, in August, 2000, the Commission permitted PG&E to enter into forward contracts with entities outside of the BFM.

Market Fundamentals

Before the dramatic escalation of spot market prices that began May 2000, there were ample signs that pointed to a meaningful probability of major market price increases during the record period. Using information that was known or should have been known to PG&E in the second half of 1999 or early 2000, La Capra Associates conducted for the Office of Ratepayer Advocates ("ORA") an assessment of the supply/demand outlook and other cost factors affecting the California electricity market. The assessment concluded that there was a meaningful risk of large price increases during the record period.

For example, electricity demand in the West had been growing, and was forecast to continue growing, without corresponding increases in the construction of new generating capacity. Further, the Western power market had not been tested in recent years by adverse outcomes for market drivers such as hydroelectric production, weather-driven peak demands and generator outages. Information that was available at the time regarding these and other market fundamentals, along with experience in other electricity markets in this country, indicated that the historical California spot prices were not a good indicator of how market prices for the record period would turn out. It was foreseeable that spot market prices would increase, and that there was a meaningful probability of large price increases.

Other Cost Risks

In addition to spot market price risk, PG&E was exposed to several other cost risks that had the potential to increase its exposure to future spot market prices. These risks, which included the switching of Qualifying Facility ("QF") suppliers to PX-based

Short-Run Avoided Cost ("SRAC") pricing, ancillary service costs, and the correlation between high prices and high loads, indicated the need for a more aggressive hedging strategy than might have been appropriate in the absence of such risks.

PG&E's Procurement Strategy

Despite these signs of rising prices and the authority provided by the Commission's July 1999 order, PG&E did not begin to purchase in the BFM for delivery in the record period until **(REDACTED)**, by which time BFM prices had increased above the 1999 levels. Further, because of concerns about how BFM costs would be recovered, the hedge targets under PG&E's initial strategy fell far short of the regulatory limits in effect at the time. Even after receiving authority to hedge up to its net short position through the end of its rate freeze, PG&E chose to purchase only 50 percent of that position through summer 2000 in the BFM. PG&E could have avoided the incurrence of hundreds of millions of dollars in power costs by developing and executing a reasonable hedging strategy. PG&E's ongoing financial exposure contributed to a deterioration of its business position, to its credit risk, and to its ultimate inability to meet its procurement obligations to customers.

Alternate Procurement Strategy

Based on market fundamentals and other cost risks, PG&E should have done several things differently. First, PG&E should have begun purchasing promptly. PG&E had a large net short position, and it should have begun utilizing its initial BFM purchasing authority to reduce that position during summer 1999. Second, PG&E should have fully utilized its initial BFM purchasing authority by early 2000. Third, once the Commission authorized (in early March 2000) PG&E to purchase up to its net short position in all months through the end of its rate freeze, PG&E should have made BFM purchases at a pace sufficient to fill most of its estimated net short position by the month of delivery. Had PG&E developed and executed such an alternate strategy, PG&E would have locked in fixed prices for most of its net short position, and lowered its purchased power costs during the period July 2000 through December 2000 by $434 million, relative to the actual costs that PG&E incurred.

I. INTRODUCTION

Q. Will you please state your name and business address?

A. My name is Douglas C. Smith. I am the Technical Director for La Capra Associates located at 20 Winthrop Square, Boston, Massachusetts 02110.

La Capra Associates ("La Capra") is a consulting firm specializing in electric industry restructuring, energy planning, market analysis, and regulatory policy in the electricity and natural gas industries. For twenty years, we have served a broad range of organizations involved with energy markets -- public and private utilities, energy producers and traders, financial institutions and investors, consumers, regulatory agencies, and public policy and research organizations. Over the past several years, our firm has worked extensively on a broad range of electric industry restructuring issues in many of the states that have been investigating or implementing restructuring.

Q. On whose behalf are you testifying in this docket?

A. I am appearing on behalf of the Office of Ratepayer Advocates ("ORA") of the California Public Utilities Commission ("Commission").

Q. Please state your qualifications and background.

A. I am an electric power industry planning and transactions specialist with 16 years of experience in areas including power systems planning and analysis, wholesale and retail power transactions, and electric utility rates. I have participated in restructuring-related activities in Pennsylvania, Massachusetts, Vermont, New Jersey and Ohio. I have managed the electric power supplies of several electric utilities, and have advised several electric utilities regarding their power transactions and risk management strategies. This means that I have a working familiarity with many of the issues and the types of decisions that Pacific Gas and Electric Company ("PG&E") faces in managing its power procurement responsibilities. I presently assist several retail electricity customers, including the National Railroad Passenger Corporation ("Amtrak"), in the procurement of retail generation service from competitive suppliers. I have presented testimony before state regulatory authorities in California, Nevada, Pennsylvania, Massachusetts, New Hampshire, New Jersey, Vermont, Arizona, Wyoming and Puerto Rico.

I have participated in numerous generation asset valuation and competitive market assessment projects on behalf of merchant generating companies, electric utilities, state regulatory and consumer agencies, and end-users. During the past two years, I have reviewed the power transactions of the San Diego Gas & Electric Company on behalf of the ORA, the California Department of Water Resources ("DWR") on behalf of the California Bureau of State Audits, PacifiCorp on behalf of the Wyoming Industrial Energy Consumers ("WIEC"), and the Nevada Power Company on behalf of the Bureau of Consumer Protection.

A copy of my resume is included in Exhibit DCS-1.

II. PURPOSE OF TESTIMONY

Q. Please describe your understanding of the purpose of this proceeding.

A. Prior to July 1999, electric utility power procurement decisions were limited to purchases in the California Power Exchange ("PX") day-ahead and hour-ahead markets and the California Independent System Operator ("CaISO") real-time market.[1] In July 1999, the Commission authorized PG&E and Southern California Edison ("SCE") to meet a portion of their bundled retail load by purchasing power in the PX's new Block-Forward Market ("BFM"). That authority was expanded and extended several times before and during the record period in this proceeding, which is July 1, 2000 through June 30, 2001.

On December 19, 2001, ALJ Barnett issued a ruling that identified the issues in the proceeding as the reasonableness of: (i) PG&E's entries to the generation memorandum account and to the Transition Cost Balancing Account ("TCBA"); and (ii) PG&E's procurement practices. On March 22, 2002, the Commission granted the ORA's motion to bifurcate the proceeding into a procurement practices phase, including bilateral contracts, and an other-issues phase.

Q. What is the purpose of your testimony in this phase of the proceeding?

A. The purpose of my testimony is to assess the reasonableness of PG&E's power procurement practices affecting power supply costs for the record period.

I approach this proceeding from the perspective of a market practitioner. La Capra has assisted numerous utility and end-user clients in managing their power supply costs and developing appropriate transactions to meet their needs and risk tolerances. Many of the issues and choices that our clients face provide a useful perspective regarding the power procurement outlook that PG&E faced as it looked forward to the record period.

In particular, I respond to the following assertions in PG&E's direct testimony filed January 11, 2002:

1. "PG&E appropriately exercised the authority provided by the California Public Utilities Commission (Commission) Resolutions E-3618, E-3658 and Decision 00-08-023;" [Testimony at page 2-1.]
2. "In March, the Commission granted PG&E the authority to use the new BFM instruments and increased the quantity PG&E could purchase under forward contracts up to the net short position. However, the Commission did not settle the cost recovery question until the issuance of the PTER 2 decision on June 8, 2000." [Testimony at page 2-3.]
3. "the potential benefits of hedging to PG&E ratepayers and shareholders were uncertain and diminished, under PG&E's specific circumstances, due to the regulatory structure of the California markets during and prior to the record period—specifically, the rate freeze and the ambiguity regarding recovery of BFM costs;" [Testimony at page 2-5.]

My testimony does not address how or whether PG&E should have hedged price risk exposure after December 31, 2000. After that date, the responsibility for

[1] The day-ahead and hour-ahead markets are markets for the supply of power at least one day and one hour before delivery to buyers respectively.

supplying the net short, and for recovering the associated costs, was transferred to the California Department of Water Resources ("DWR") by a statute known as AB1X. While any unreasonable failure by PG&E to hedge post December 31, 2000 would increase DWR's revenue requirement, it would not affect the entries to TCBA. Thus, the remedy for, and assessment of, any unreasonable PG&E acts as they pertain to the post December 31, 2000 period are beyond the scope of this proceeding.

Q. You said that the purpose of this phase of the proceeding is to review the reasonableness of PG&E's power procurement practices. What is your understanding of the meaning of "reasonableness"?

A. In this testimony, I use the terms reasonableness and prudence interchangeably. My understanding of the term reasonable procurement practices is that a utility is expected to make reasonable procurement decisions in the context of what was known or should have been known at the time the decision was made. Procurement practices and decisions should not be measured against a perfect hindsight standard. Rather, the regulator should determine whether the utility was effectively managing and implementing its procurement responsibility consistent with regulatory policy and authorized procurement practices.

In the specific case of power procurement in forward and spot markets, which my testimony addresses, reasonable practices include:

- The establishment of a systematic assessment of market fundamentals, expected future market prices, the potential range of price outcomes, and the impact of those potential outcomes on the utility's power costs;
- The establishment of an appropriate tracking mechanism to monitor the net short position that the utility is responsible for serving;
- The development of a sound procurement strategy including a clear set of decision criteria to determine how much, when and how rapidly forward purchases should be made; and
- Effective implementation of the strategy.

Q. Does your testimony address all aspects of PG&E's power purchases for the record period?

A. No. Because the price PG&E received for generation it sold to the PX was the same as the price it paid for generation purchased from the PX, my testimony focuses on PG&E's procurement strategy for supplying the portion of its load not covered by retained generation and purchased power (commonly referred to as the "net short position" or "open position"). By this I mean that I examined what PG&E bought, when it bought, and whether an alternate BFM procurement strategy (particularly an alternative mix of forward and spot purchases) would have been prudent under the circumstances.[2] I focus primarily on the amounts and timing of purchases in the BFM for delivery in peak hours. The focus is on peak purchases because: (i) the peak period was likely to feature the greatest market price risk; and (ii) PG&E was not authorized to purchase off-peak hedge products prior to August 3, 2000, long after spot market prices had increased substantially.

As regards quantification of the costs and benefits of BFM purchases, my calculations end December 31, 2000, shortly before PG&E ceased its role as the buyer of the net short due to credit limitations. As noted above, after that date the responsibility for supplying the net short, and for recovering the associated costs, was transferred to DWR. At approximately the same time, PG&E's block-forward contracts were seized by the State and assigned to DWR to help assure delivery of supply under their original terms.[3]

III. OVERVIEW OF POWER NEEDS

Q. Please provide a brief overview of the PG&E system.

[2] The BFM was an exchange run by the PX that matched bids to buy power with offers to sell power a month or more ahead of delivery at either NP15 or SP15 market hubs. The services offered consisted initially of a single "Peak" product covering the hours 6:00 a.m. to 10 PM, Monday through Saturday (holidays excluded) for delivery in future months. Capacity was traded in lots of 1 or 25 MW. The primary purpose of the BFM was to allow participants to manage their price risk in the PX energy markets. In November 1999, the PX introduced a quarterly BFM product. Under this new product, blocks of peak power could be traded for an entire quarter at a single price.

[3] DWR's report captioned Power Supply Revenue Bonds, dated September 5, 2002, pages xiv and A-58.

A. PG&E provides retail electric service to approximately 4.8 million electric customers in Northern and Central California. In 2000, PG&E had a peak demand of over 18,000 MW, energy requirements of almost 90 million MWh, and owned approximately 7,000 MW of generation capacity. These resources consist of the 2,160 MW Diablo Canyon nuclear power plant, 3,890 MW of hydroelectric generating capacity, and 580 MW of gas-fired thermal units that are necessary for areas that are transmission constrained.[4] In recent years, PG&E's hydroelectric facilities operated at an average annual capacity factor of 56 percent. In addition to owned generation, PG&E had about 1,600 MW of bilateral power purchase contracts.

One part of PG&E's service area is located north of Path 15, or NP15, while the other is bounded by Path 15 to the north and Path 26 to the south, or ZP26.[5] The NP15 portion of PG&E's service area is located in Northern California and the ZP26 portion in Central California. Historically, PG&E's loads have exceeded its resources in NP15 but have fallen short in ZP26.

PG&E also purchased about 4,300 MW of power under long-term firm contracts with QFs.[6] Prior to July 1999, the balance of PG&E's power requirements were purchased in the PX day-ahead market, the PX day-of market, and the CaISO real-time imbalance market, which I refer to collectively as the "spot market." After July 1999, PG&E was allowed to purchase in the PX's BFM.[7] The prices in the spot market were determined by the balance of supply and demand at the time of the transaction. These prices would vary based on changes in the supply and demand balance (e.g., demand growth, hydro production, generating plant outages) and changes in the supply curve (e.g., natural gas prices, NOx emission allowance prices, generator bidding behavior).

[4] DWR's Power Supply Revenue Bond report, September 5, 2002, Appendix II.
[5] Path 15 is a system of transmission lines that interconnect the Los Banos, Gates, and Midway Substations. Path 15 has historically created constraints in the delivery of power between northern and southern California.
[6] DWR's Power Supply Revenue Bond report, September 5, 2002, Appendix II.
[7] PG&E also received authority in August 2000 to enter into bilateral contracts outside of the PX.

Experience in U.S. electricity markets had shown spot market prices to be very volatile, particularly in periods when the supply/demand balance was tight. Thus, because some of PG&E's power requirements during the record period were subject to potentially volatile spot market prices, and because retail rates were capped, PG&E faced cost risks that had to be managed. Exhibit DCS-2 provides a monthly breakdown of PG&E's actual loads and generation resources during peak hours and the resulting net short position.

Q. What was PG&E's projected need for market purchases during the record period?

A. Projections of the net short position were presented in PG&E's PX Block-Forward Trading Daily Report ("Daily Report").[8] In late January 2000, the Daily Reports showed PG&E to be short on a forecast basis by about **(REDACTED)** on average for the third quarter (July through September) 2000. By late April, PG&E had increased its third quarter estimate to approximately **(REDACTED)** and added estimates for fourth quarter 2000 and first quarter of 2001 of **(REDACTED)** respectively. This updated projection remained in effect until mid-December 2000 when PG&E increased its first quarter 2001 estimate to approximately **(REDACTED)**. In January 2000, PG&E estimated the net short for second quarter 2001 at approximately **(REDACTED)**. These changes are summarized in Exhibit DCS-3.

The Daily Reports presented the net short position on an average MW basis during peak hours. This fitted well with standard wholesale trading blocks (i.e., 6 days/week, 16 hours/day), although PG&E's actual needs were somewhat biased toward peak hours and peak days, as opposed to a flat amount during all peak hours. As a result, a balanced monthly position on average would actually feature surplus energy in some hours, and the need for additional energy in others.

[8] The net short position was defined as the amount by which the demand of PG&E bundled retail customers exceeded the supply PG&E provided in that hour, excluding any BFM purchases that PG&E had already made. PG&E calculated its net short position on an hourly basis, and averaged the result over the delivery hours of the BFM product.

Q. Could PG&E's actual net short position turn out differently from forecast?

A. Yes, variations in electricity supply and demand would be expected to cause PG&E's actual net short to differ from forecast. For PG&E, variations in hydroelectric production, temperature-driven changes in demand, and the availability of the Diablo Canyon plant are primary factors that can drive changes in the net short. Such variations were unlikely to fundamentally erode PG&E's net short over sustained periods and could, of course, cause the net short to turn out above forecast as well.

Q. Did PG&E project its net short position for any portion of the record period prior to January 2000?

A. No, it did not. PG&E began forecasting its net open position for the initial months of the record period in early January 2000.[9]

Q. Did PG&E explain the changes in its net short projections for the record period?

A. PG&E's methodology for estimating its net short position is explained in the document "Electric Trading and Risk Management Program Operating Procedures" and it has identified the factors that caused the projections of the net short to change. However, PG&E has not provided the individual load and resource assumptions underlying those projections.[10] As a result, I have not been able to determine conclusively whether the net short projections represent a reasonable base case estimate of its market requirements. PG&E has not retained the individual load and resource components that made up the April 27, 2000, net short position forecast.[11]

Q. Do the above mentioned net short projections relate to PG&E's total system?

A. Yes, they do. The projections represent the net of PG&E's projected positions at NP15 and ZP26, which reflect PG&E's practice of selling all of its resources in

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[9] See PG&E Response to ORA Data Request ATCP Ph 2 PG&E -22-Question 3
[10] See PG&E Response to ORA Data Request ATCP Ph 2 PG&E -22-Question 7

the PX and CaISO spot markets (NP15 resources were sold in the NP15 zone and ZP26 resources were sold in the ZP26 zone), and buying to cover all of its load in the same markets (NP15 purchases for its NP15 load and ZP26 purchases for its ZP26 load). PG&E contends that it was reasonable to net long and short positions because historical daily spot market prices at NP15 and ZP26 were generally highly correlated.[12]

IV. HEDGING AUTHORITY

Q. Please explain hedging as it pertains to this proceeding.

A. In Resolution E-3618, issued July 8, 1999, the Commission clearly expected PG&E to use its BFM authority for hedging.[13] Prior to that time, approximately **(REDACTED)** of the annual energy requirements to serve bundled retail load was supplied by retained generation, such as the Diablo Canyon nuclear plant and various hydroelectric facilities, and purchased power contracts with qualifying facilities ("QFs") and other bilateral suppliers. The remaining (**REDACTED)** was purchased in the spot market. The amount actually purchased in the spot market varied considerably in percentage and MWh terms by season and by peak/off-peak hours. In other words, PG&E's net short position was the amount of power that it was obligated to sell to bundled service customers for which it had no physical or contractual supply secured in advance of the time required to deliver. The price for the power bought in the spot markets is, of course, uncertain until the day-ahead or day-of transactions. Absent any ability to purchase forward, PG&E's substantial net short position was subject to all of the volatility in the spot market. To the extent that spot market prices increased, PG&E's purchase power costs would increase with them.

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[11] Ibid

[12] PG&E only used 25 percent of its ZP26 long position in the months of July through October 2000 when calculating the net short position. See PG&E Response to ORA Data Request ATCP Ph 2 PG&E -22-Question 8. According to PG&E, the 25 percent is a conservative assumption and not the result of detailed analysis. See also PG&E Response to ORA Data Request ATCP Ph 2 PG&E -19-Question 3.

[13] See Resolution E-3618, page 5, par 2.

A block forward contract is a contract for the physical delivery of a specified amount of power at a predetermined time and fixed price. The BFM provided PG&E an opportunity to buy at a fixed price some of the power needed to meet its load obligation with block forward contracts rather than exclusively from spot market at uncertain prices.

In the context of this proceeding, “hedging” refers to the use of forward contracts (taking forward positions) to meet some or all of PG&E’s net short position. The forward contracts reduce the overall uncertainty of the cost of the supply portfolio by securing a portion of the supply in advance at known prices. A hedging transaction is one that locks in a fixed price today for a purchase or sale that would otherwise have to be made in the future at an uncertain price.

Q. Please explain the role of hedging in mitigating price spikes.

A. The primary motivation for hedging is to reduce the potential for variance in the firm’s future costs (in the case of a buyer) or revenue (in the case of a seller) and to reduce the risk of unacceptable or unaffordable potential market price outcomes.

In the context of this proceeding, the BFM offered PG&E an opportunity to reduce its substantial net short position with forward contracts. These block forward contracts could be used to reduce the exposure to the spot market prices for periods when there was a meaningful possibility that spot market prices could turn out substantially above the BFM price.

Forward contracts at fixed prices represent a tradeoff, foregoing the uncertain prospects for higher or lower prices in the spot market in exchange for the certainty of the price of the forward contract. This will not lead to the lowest cost outcome in every period, as buying forward requires the buyer to forego some potential low price outcomes for the protection against the possibility of unacceptably high cost outcomes.

Q. Please describe PG&E's initial authority to enter into forward contracts.

A. The Commission first provided PG&E authority to make forward purchases in Resolution E-3618 issued on July 8, 1999. This order allowed PG&E to purchase BFM products approved by the FERC in Order No. 61,203 for delivery through October 31, 2000. The allowed amount of BFM purchases were capped at one-third of PG&E's historical minimum load. This last restriction yielded monthly limits that averaged approximately **(REDACTED)** for summer 2000. For the purposes of context, the **(REDACTED)** purchase limit might be compared to projected monthly peak period demands for the record period of between **(REDACTED)** and projected peak period net short positions for the summer period that varied from **(REDACTED(** depending on the date the projection was made.[14]

Q. Did PG&E later request additional BFM purchase authority?

A. Yes, it did. PG&E returned to the Commission in January 2000 to request authorization to expand its BFM purchase limits and the range of BFM products that could be purchased. PG&E argued that it needed the higher BFM purchase limits in order to increase its opportunity to hedge price risks. On March 6, 2000, in Resolution E-3658, the Commission agreed that PG&E required additional flexibility to insure against price spikes, and authorized it to purchase up to its quarterly net short positions as well as buy "superpeak" and "peak shoulder" energy products in the BFM. Resolution E-3658 also extended PG&E's hedging authority until the end of its rate freeze.[15]

Q. Did the Commission subsequently expand PG&E's authority to purchase forward?

[14] See PG&E Response to ORA Data Request ATCP Ph 2 PG&E -14-Question 1 for the lower end of the net short range and PG&E's Daily reports for the upper end.

[15] The superpeak product corresponds to the hours from 12:00 p.m. to 8:00 p.m., Monday through Saturday, and the peak shoulder product to the remaining peak hours; 6:00 a.m. to 12:00 p.m., and 8:00 p.m. to 10:00 p.m.

A. Yes. Following the March 6, 2000 Resolution, the Commission expanded PG&E's BFM authority on three separate occasions. On June 8, 2000, the Commission, in Resolution E-3672, authorized PG&E to participate in the PX's forward market for ancillary services. Ancillary services are, stated generally, the services required to maintain system reliability.[16]

In July 2000, the Commission, in Resolution E-3683, authorized PG&E to participate in the daily and balance-of-the-month block-forward markets. The resolution allowed PG&E to purchase up to 1,000 MW per day more than the limit on monthly BFM purchases contained in Resolution E-3658. That is, the new combined limit for the monthly, daily, and balance-of-the-month BFM purchases on any one day was set at PG&E's quarterly net short position plus 1,000 MW. Finally, on August 3, 2000, the Commission authorized PG&E to enter into bilateral contracts that expire prior to December 31, 2005, but did not change the regulatory limit in effect at that time.

V. PG&E'S PROCUREMENT STRATEGY

Q. After receiving authority to participate in the BFM, what should PG&E have been doing to evaluate its BFM purchase options?

A. As noted above, I believe a prudent course of action would have included:

- The establishment of a systematic assessment of market fundamentals, expected future market prices, the potential range of price outcomes, and the impact of those potential outcomes on the utility's power costs;
- The establishment of an appropriate tracking mechanism to monitor the net short requirement that PG&E is responsible for serving;

[16] Such services consist of spinning, non-spinning, and replacement reserves, regulation, voltage control, and black start capability. Spinning reserve is the portion of unloaded synchronized generating capacity that is capable of being loaded in 10 minutes. Non-spinning reserve is the portion of off-line generating capacity that is capable of being loaded in 10 minutes. Replacement reserve is generation that is available and can begin production of electricity within one hour.

- The development of a sound procurement strategy including a clear set of decision criteria to determine how much, when and how fast forward purchases should be made; and
- Effective implementation of the strategy.

Q. Please describe PG&E's BFM strategy.

A. Despite receiving authority in July 1999 to hedge up to one third of its historical minimum load through October 31, 2000, PG&E's initial hedging strategy was limited to summer 1999 and to forward contracts for delivery one or two months in advance.[17] PG&E did not develop a hedging strategy that extended through October 2000 until January 2000.[18] Because of concerns about how BFM costs would be recovered, PG&E established hedge targets under the initial and updated strategies that were short of the regulatory limits at that time.[19] PG&E's concerns regarding the recovery of BFM costs were summed up as follows:

> given the uncertain end-date of PG&E's rate freeze, PG&E's ability to recover its BFM costs is unclear, ….. This uncertainty makes it very difficult for PG&E to continue hedging price risk using the BFM. (Advice Letter 1960-E, January 19, 2000)

Even after receiving authority to hedge up to its net short position through the end of its rate freeze, PG&E established targets to purchase only 50 percent of that position in the BFM, and the remainder from the spot market. In order to meet its 50 percent target, PG&E elected to spread its BFM purchases for delivery in a particular month over a **(REDACTED)** time frame rather than make larger purchases over a shorter time period. According to PG&E, concentrating

[17] PG&E's initial strategy was ultimately extended through January 2000.
[18] See January 12, 2000 and January 19, 2000 URMC meeting minutes at bates range PGEATCP 000453, (ATCP ORA-001) of PG&E response to ORA data request PG&E-1, Question 29.
[19] In January 2000, PG&E adopted a 30 percent hedge target for March through May 2000 and 50 percent for June 2000 on. See PG&E Response to ORA Data Request ATCP Ph 2 PG&E -8-Question 3.

purchases in a short period of time exposes the buyer to the risk that prices will fall after the purchases are made.[20]

PG&E maintained the 50 percent hedge target until October 2000, when it was increased to **(REDACTED)**, which PG&E maintained until its BFM hedging program was suspended in early 2001 due to credit limitations.

PG&E began to purchase in the BFM for delivery in the record period in **(REDACTED)** and continued at a monthly rate of between **(REDACTED)** was replaced with bilateral power purchases, at least until **(REDACTED)**. Most of the bilateral energy was bought in October 2000. PG&E's bilateral purchases included peak ("6x16"), off-peak, and all-hour ("7x24") purchases, whereas its BFM purchases included only peak purchases. Consequently, with the implementation of the bilateral program, PG&E began to hedge a portion of its off-peak net short position for deliveries in October and subsequent months.

Q. You state that PG&E did not begin to purchase in the BFM for delivery in the record period until (REDACTED). Was this decision supported by an analysis of the optimum time to make forward purchases to meet the established hedge targets?

A. No, PG&E did not conduct a formal analysis of when to make forward purchases for hedging.[21]

Q. Was PG&E's decision to limit its hedging to just 50 percent of the projected net short based on an analysis of potential future market conditions?

A. No. PG&E adopted the 50 percent hedge target because it believed this level diversified the risk between BFM forward prices and spot market prices. According to PG&E, hedging more than 50 percent would have replaced spot market price risk with BFM price risk. That is, PG&E was concerned that the risk

[20] PG&E also acknowledged that spreading its purchases over time risked paying higher prices in a rising market.
[21] See PG&E Response to ORA Data Request ATCP Ph 2 PG&E -19-Question 1.

of lost value, due to spot prices turning out lower than the hedge price, would increase as the hedge fraction increases.

Q. Was PG&E's strategy reasonable?

A. No, it was not. PG&E has termed its strategy as a "balanced hedge." PG&E has provided no documentation that indicates what it was balancing. A "balanced hedge," (e.g. one that balances risk and reward) bears no necessary resemblance to a 50% hedge. As shown in Section VI, market fundamentals indicated that there was a risk of large spot market price increases, and that the potential magnitude of price declines was much smaller. In these circumstances, it would have been appropriate for PG&E to hedge a high percentage of its net short position.

VI. MARKET FUNDAMENTALS

Q. How are you using the term market fundamentals?

A. In its broadest sense, market fundamentals refers to the balance or imbalance of supply and demand, the price effects of imbalance, and the production costs to supply a good or service, in this case, electricity. The fundamentals I review in this section of my testimony encompass those necessary to make justifiable conclusions regarding supply and demand balance and its consequences, including historical prices, demand, reserve margins, hydroelectric generation, outage rates, public information on the adequacy of supply, ownership, price caps, NOx allowance prices and conditions, and natural gas prices.

Q. Could you summarize what this review shows?

A. Demand was increasing, while supply was not. Historical spot market prices reflected relatively benign conditions, and had not been tested by inadequate supply. When inadequate supply had occurred in other U.S. markets, prices had spiked severely. Above-average demand due to economic growth or abnormal weather, or below-average supply due to poor hydro or outages for other generation could test the balance of supply and demand, and lead to price spikes that had occurred elsewhere. Publicly available information signaled the prospect for tight market conditions. Meanwhile, there was evidence that generators were likely to employ more aggressive bidding strategies, the supply of NOx allowances was strained, and the natural gas market in 1998 and 1999 had not been particularly volatile.

Q. How did PG&E analyze the potential spot market prices that its customers would face during the record period?

A. PG&E's primary source of market intelligence was PIRA, a private consulting firm providing market research and analysis of electricity, oil and natural gas industries. This information was generally conveyed to PG&E through monthly reports that addressed in considerable detail the key drivers of power market prices that I discuss below. These reports also contained projections of peak spot market electricity prices that extended, beginning with the August 1999 issue, into the record period.

In addition to the market information provided by PIRA, PG&E employees were assigned responsibility for reporting changes in fundamentals, most notably electricity produced by hydroelectric facilities and natural gas prices. However, PG&E did not begin to develop its own projections of spot market prices until Summer 2000.[22]

Q. What market information did PG&E have, or should it have had, in late 1999 and early 2000?

A. The following portion of my testimony will review the history of PX prices; the key drivers of electricity market prices in California; and the information that PG&E could have used to evaluate the outlook for the market drivers and market prices.

1. Historical Spot Market Prices

Q. Please summarize the historical spot market electricity prices in California.

A. When PG&E considered the outlook for spot market prices that it would face in the record period, one point of reference was the historical PX spot prices for Zone NP-15, the zone in which the majority of PG&E's load is located. Exhibit DCS-4 presents the average of hourly day-ahead PX market prices in peak hours, for each month since the day-ahead market began operation in April, 1998.[23] Notable features of the historical spot market prices before summer 2000 include:

- On-peak energy prices averaged about $34/MWh in 1998 and 1999, with noticeable monthly variations. On-peak prices for the third quarters of 1998 and 1999 averaged about $43/MWh and $41/MWh, respectively.
- On-peak energy prices tended to be lowest in the spring, when hydroelectric production in California and the Pacific Northwest was high. Prices tended to be highest during summer months, when average and peak electricity demands were much higher than in other months.
- During many months, and particularly during summer months, maximum hourly prices in the day-ahead market exceeded $130/MWh, more than three times the average on-peak price.

Q. What other information sources could PG&E have used to develop its view of electricity market prices for the record period?

A. Other available information sources included at least the following:

- Historical information about key market drivers (e.g., electricity demand, hydroelectric production);
- Forecasts of the market drivers by PIRA and other market analysts;
- Analyses of supply and demand conducted by parties such as PIRA, WSCC and CEC.
- Trade press reports; and
- Electricity market results from other regions of the country.

The next portion of my testimony will address the market outlook for the record period in detail, using the sources above. My review of the outlook for summer

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[22] See PG&E response to ORA Data Request ATCP Ph2 PG&E-15-Question 12.

[23] Day-ahead prices were a reasonable proxy for spot market prices because PG&E had historically made most of its short term energy purchases from this market.

2000 indicates that spot prices would probably turn out higher than in recent years, and that the upper end of the range for potential prices in summer 2000 would be much higher than both the actual prices observed to date in California and the BFM prices that had been available to PG&E in 1999 and well into 2000.

2. The Balance of Supply and Demand.

Q. What are the key drivers of prices in the California electricity market?

A. I will discuss the drivers in terms of two major groups: those that influence the balance of supply and demand; and those that influence the prices at which generators are willing to offer their output.

The key factors influencing the balance of supply and demand, both within California and in the Western States Coordinating Council ("WSCC"),[24] are:

- The demand for electricity, including both the maximum demand during a period and the shape of the demand across the entire period.
- The amount of installed generating capacity, which may be expressed as a capacity reserve margin. The greater the reserve margin, all else being equal, the lower the probability of shortage conditions and associated high prices.
- The availability of the existing generating plants (and particularly low-cost sources such as hydroelectric and nuclear plants) to produce energy at any given time.

The key factors influencing the prices at which generators are willing to offer their output are:

- Fuel prices. Because most marginal generating plants in California burn natural gas, natural gas prices drive the costs and bid prices that drive the California market during many hours.
- NOx allowance prices. Major generating plants in southern California are required to hold tradable NOx allowances sufficient to cover their actual annual emissions. NOx allowances are part of the direct operating costs

[24] The WSCC covers the western part of the continental United States, Canada, and Mexico. The WSCC region includes Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Washington, Wyoming, and Utah, the Canadian provinces of Alberta and British Columbia, and the northern-most portion of Mexico.

for these plants, and it is reasonable to expect that owners would include the price of NOx allowances in their bid prices.

- Generator bidding behavior. Generators may choose the price at which they offer their output. It is reasonable to expect that generators will offer their output at prices that cover at least their variable production costs, but they may seek more. The extent to which generators ask higher prices will depend in part on the ownership patterns of capacity in the market, the business objectives and judgments of the capacity owners, and short term market conditions.

Q. Before you begin your discussion of the foregoing market drivers, please summarize your assessment of the potential effect of these drivers on California market prices during the record period.

A. An assessment of the supply/demand outlook and other cost factors affecting the Western electricity market indicates that on an expected value basis, the outlook for spot market prices during the record period was higher than actual prices in the prior year. In addition, the potential for extreme high price outcomes had increased. It was foreseeable that less favorable (but quite plausible) outcomes for several market drivers could produce much tighter conditions and much higher spot market prices.

For these reasons, higher prices were likely and the potential price range included values far above historical prices. This was true with respect to prices in summer 2000 and after. In the following pages, I will discuss many of these market drivers from the perspective of information available in the mid-1999 to early 2000 timeframe.

3. Electricity Demand

Q. Please summarize the outlook for electricity demand growth, entering 2000.

A. Electricity demand had been increasing in California and the WSCC, and was forecast to continue growing. Energy consumption for the WSCC had grown at an annual average rate of about 1.5 percent from 1996 to 1999. Peak demand for the same period had also been growing at a rate of about 1.5 percent annually. For the period 2000 through 2005, WSCC forecast peak demand to grow at an average annual rate of 2.3 percent and consumption to grow by 2.1 percent for the region as a whole. For California, energy consumption grew at an annual average rate of about 2 percent and peak demand grew at 3.3 percent, over the same period. The California Energy Commission ("CEC") forecast that California peak demand and consumption would grow at an annual average rate of 3 percent and energy consumption would grow at an average annual rate of about 2 percent for the period 2000 through 2005, fueled in part by a booming economy. On the whole, the available information indicated likely electricity demand growth of at least two percent per year, based on normal weather conditions.

Q. How does weather affect the demand for electricity in California?

A. The demand for electricity tends to increase with temperature, particularly in California and the Southwest, and the increases can be substantial. For example, a 1999 assessment of supply adequacy in California prepared by CEC Staff estimated[25] peak demand exposures under relatively normal hot weather conditions (i.e., conditions that would be exceeded once every two years), as well as for hotter conditions that might be exceeded once in five years, once in 10 years, and once in 40 years. CEC's estimates indicated that for these temperature outcomes, peak demand in the California/Mexico area would exceed the base case projection by 1,861 MW, 3,089 MW, and 4,341 MW, respectively.

4. Generating Capacity Reserve Margins

Q. Had generating capacity additions kept pace with electricity demand growth in California and other western states?

[25] "High Temperatures & Electricity Demand, An Assessment of Supply Adequacy in California, Trends & Outlook." Report of the California Energy Commission Staff, July 1999.

A. No, they had not. During the 1990s, growth in electricity demand significantly exceeded construction of new generating capacity in California, and in the WSCC as a whole. The result was a significant decline in capacity reserve margins.

According to the WSCC report "Existing Generation and Significant Additions and Changes to System Facilities" issued April 1999, only about 800 MW of additional capacity was anticipated to come online in California during 2000, representing an increase of about 1.5 percent. For the WSCC as a whole, capacity additions of about 1,423 MW were forecast, representing an increase of less than 1 percent.

5. Hydroelectric Generation

Q. Please summarize the role of hydroelectric plants in the California electricity market.

A. In-state hydro plants provide over 10,000 MW (over 18 percent) of the installed capacity available to the California market. During 1998 and 1999, these plants produced about 43 million MWh, representing roughly 20 percent of California's annual energy requirements. Hydro production is even more important to the power supply of the Pacific Northwest ("PNW") states. PNW hydro plants provide over 46,000 MW of capacity, and produce an average of about 120 million MWh of energy per year. In short, hydro production plays a much more important role in the Western market than in most other U.S. electricity markets,[26] making market prices susceptible to hydro variations in a way that most other U.S. markets are not.

The differences between wet years and dry years are very substantial. For example, in the wet year 1997 total WSCC hydro production was 300 million MWh, 97 million MWh higher than in 1994. During years of low hydro production, market prices will tend to be higher and the potential for extreme high prices is greater. This is because the drop in hydro production must be replaced

[26] For example, hydro plants provide roughly two percent of annual production in PJM and ECAR.

with output from existing high cost oil and gas generators. As I explain further below, the consequences of an increase in thermal generation are capacity constraints on the gas transmission lines serving California, lower gas inventories, and a more rapid depletion of emissions credits, each of which tend to drive spot market clearing prices to higher levels. Exhibits DCS-5 and DCS-6 illustrate the average energy production for hydro plants in the Pacific Northwest and California, respectively, for summer months in 1992 through 2000. The exhibits show that in 1998 and 1999, the first two years of the PX market, the actual monthly hydro production in each region tended to be in the middle to upper end of the historical distribution. The implication for Summer 2000 was that if hydro production were to drop to below-normal levels, the supply/demand balance in the WECC could be reduced by an average of at least several thousand MW, putting upward pressure on market prices.

6. Outage Rates for Existing Generating Plants

Q. How do generating unit outages affect the electricity spot market?

A. At any particular time, some fraction of the installed generating capacity in an electricity market is typically unavailable to generate due to a combination of planned and unplanned outages. While generator outages can be forecast to some extent based on historical data and judgment, they cannot be known in advance. When meaningful amounts of generating capacity are unavailable to generate due to outages, spot market prices tend to increase as more costly plants are called upon to replace the lost output.

An assessment of future spot market prices should take into account the effect of generating unit outages, and the fact that they cannot be known with certainty in advance. The higher the actual outage rates, the higher spot prices will tend to be. The magnitude of this effect will depend on the shape of the regional supply curve, and the portion of the supply curve at which the market is likely to settle. In particular, when electricity demand is approaching the available supply, additional generator outages can greatly increase spot market prices.

Q. What is the range of potential generating unit outages affecting the California spot market?

A. WSCC summaries of recent historical loads and resources[27] indicate that in the summer months of 1998 and 1999, total outages of California generating capacity at the time of the monthly system peak load ranged between 264 MW to 1,892 MW. These outages, which amount to between 0.5 percent and 3.5 percent of the state's total capacity resources at that time, represent a practical low bound. Significantly, these figures represent outages during only the peak hours of each month. FERC Staff's November 2000 report[28] showed that for each of the summer months in 1999, average capacity out of service in the CaISO area across all hours (not just the hour of the system peak demand) was much higher, ranging from 1,190 MW to 2,398 MW. These outages represented roughly 2.2 percent to 4.4 percent. The longer term history also shows much higher outage levels. The CEC Staff's July, 1999 "Assessment of Supply Adequacy in California" showed outage levels closer to ten percent during summer peak conditions. In short, generator outages during recent summers had not been high by historical standards. Publicly available documents indicated that plausible higher outage levels would produce a significantly tighter supply/demand situation.

[27] WSCC Summary of Estimated Loads and Resources.

[28] "Staff Report to the FERC on Western Markets and the Causes of the Summer 2000 Price Abnormalities." November 1, 2000.

7. Public Assessment of Supply Adequacy

Q. Going into 2000, how were market observers characterizing the balance of electricity supply and demand in California?

A. One point of reference was the CEC Staff's July 1999 assessment of supply adequacy.[29] This analysis featured a detailed dispatch simulation analysis of peak conditions for the WSCC region, and showed a reserve margin of about 7 percent for California under base case weather conditions. Under this outcome, California would have approximately enough operating reserves to meet WSCC's target criterion. Significantly, the report assumed that no nuclear units (with average capacity of over 1,000 MW each) would be unavailable due to forced outages. An outage of even one of the California nuclear units would reduce the available capacity margin by several percent. The CEC Staff analysis also showed that hotter than normal weather conditions could increase electricity demand by several thousand MW, and it did not test California's capacity margin under unfavorable but realistic supply/demand outcomes such as above-average generating unit outage conditions or poor hydro conditions.

In summary, the CEC Staff analysis showed that very plausible outcomes for key supply and demand parameters would produce a tight capacity situation and the potential for shortage conditions. The specific response of Western market prices to tight supply conditions was uncertain, in part because the region the Western power market had not been tested in recent summers by adverse outcomes for market drivers such as hydroelectric production, weather-driven peak demands and generator outages. As I will show later in this section, experience in the Eastern U.S. markets had shown that tight conditions can produce very large price increases.

[29] "High Temperatures & Electricity Demand, An Assessment of Supply Adequacy in California, Trends & Outlook." Report of the California Energy Commission Staff, July 1999.

Q. Did trade press reports indicate the potential for tight market conditions for summer 2000?

A. Yes. A number of articles published in *Power Markets Week* during the period of January 2000 through May of 2000 discuss two main drivers of electricity prices, demand and hydro availability. The January 24, 2000 article titled "Western Futures Close Higher; Traders Wonder: Is Supply Glut Finally Over?" talks about the unusually high level of prices despite the presence of light load. One trader is quoted as saying "We've got $38 power [meaning a spot price of $38/MWh] in California with no load. It looks as though the West is shaping up to be quite a bit tighter than its reputation would suggest." The article goes on to state that "The region's strong economy may be setting a new price floor that could have implications for the summer…"

The February 28, 2000 issue of *Power Markets Week* reports the remarks of CEC Chairman William Keese warning of power shortages (that is to say, blackouts) in California if the region experiences a heat wave. The article further says "The comments added more momentum to the upward trending market that has already been influenced by predictions of below-normal hydro supplies and forecasts of strong load growth."

Questions about the availability of hydro supplies were surfacing in the trade press as early as February. The February 14, 2000 issue of *Power Markets Week* reports the release of the North West River Forecast Center's latest forecast of Columbia River Basin flows. The report is a revision to an earlier forecast that revises down the April through September flows from 106 percent of normal to normal. The article quotes one trader as saying, "We've had plenty of water and mild temperatures and haven't been able to get daily prices south of $30. If the flow forecasts continue to drop, it could be a very tight summer."

Q. How does a tightening supply/demand balance affect electricity market prices?

A. In a tightening market (i.e., when demand is increasing relative to supply), the intersection of supply and demand generally occurs higher on the supply curve. As generating plants with higher costs (i.e., those with lower thermal efficiency, higher fuel costs, or greater emission allowance costs) are called into service, the market clearing price increases.

One meaningful price transition occurs when relatively inefficient simple cycle combustion turbine units are called into service. Based on their relative thermal efficiencies, bid prices from older simple cycle combustion turbines will typically be much higher than those from steam units facing the same fuel prices. During hours when the less efficient plant is called upon to operate, market prices would be much higher than when the former is the marginal plant in the market.

Other examples are possible of course. However, the principal point is that tighter supply conditions translate to more costly plants being called upon to operate, resulting in higher spot market prices. The magnitude of price increases will vary based on a range of factors that affect the supply curve. During the summer months, when PG&E's retail loads (and those for the WSCC as a whole) are higher than at other times of the year, tightening supply conditions have the potential to cause the greatest price increases.

Q. How are spot market electricity prices affected when there is a potential for shortage conditions?

A. When electricity demand approaches the available supply, spot market prices tend to increase dramatically and they may settle at levels far above the variable costs of the marginal generating plants. This phenomenon, which has been observed in numerous electricity markets, is understandable from two perspectives.

First, consider the income requirements of a peaking plant that sets the market during periods of tight supply. If that plant offered its output at only its variable cost of production, it would run the risk of not covering its fixed costs during the few hours each year in which it operates. For example, if a peaking plant faced fixed costs (including carrying charges) of $50/kW-year, and expected to operate 200 hours per year, it would need to achieve average revenue of almost $300/MWh during those operating hours to be profitable for the year.

Second, the owners of peaking plants know that they are near the end of the supply curve, and the conditions that stimulate maximum demand (i.e., extreme hot weather) are well understood and fairly easy to observe. When peaking units are called upon to operate the market has essentially exhausted its cheaper alternatives, including imports, and competition among suppliers is naturally more limited. Considering that electricity demand has limited price elasticity at present, such plants may be able to essentially name their price during extreme peak conditions, subject to market price caps.

Experience in eastern markets such as ECAR, Entergy and PJM during 1998 and 1999 had clearly shown that during tight supply conditions, daily and hourly energy prices could increase to several hundred percent of the prices observed on more typical days. For example, peak energy prices in ECAR[30] for June through August of 1998 averaged $150/MWh, more than four times the prior year's average for the same months. The well-publicized price increases in eastern markets were associated primarily with tightening supply conditions, driven by many of the same factors (e.g., declining reserve margins, hot weather, and generating unit outages) that affected prices in California in summer 2000. Exhibit DCS-7 illustrates daily peak energy prices[31] for the Cinergy market during the summer of 1998. Similar price trends were observed at other eastern trading hubs including Entergy and PJM prior to 2000.

[30] As measured by Power Markets Week's daily peak index price.
[31] The prices reflect a daily index of bilateral trades, as reported by Power Markets Week.

Q. Did other reports during 1999 address the potential for market price increases in the West?

A. Yes. Back in June 1999, the ICF/Kaiser Consulting Group, a large, established energy consulting firm, had broadcast a clear warning message regarding California spot prices, citing the market drivers discussed in my testimony. Specifically, in announcing its 1999 Bulk Power Outlook report, ICF/Kaiser reported that surplus hydro conditions in recent years had masked an emerging shortage condition in the Western market. Other highlights from ICF/Kaiser's announcement (as reported in the June 7, 1999 edition of *Power Markets Week*) included:

- "The West stands at least a one-in-three chance of experiencing price spikes similar to those seen in the Midwest market during the summer of 1998."
- Price spikes were more likely to occur in summer 2000 than summer 1999, due to expected favorable hydro and weather conditions in 1999.
- Despite above-average hydro supplies, Western market prices had been increasing.
- In the event of above-normal summer temperatures, supplies could be very tight. "Pre-conditions are there for a very precarious situation…"

Q. Did PIRA warn PG&E about potential shortage conditions in summer 2000 and higher spot prices?

A. **(REDACTED)**

Q. Did PIRA also caution PG&E about the risks surrounding its reference case spot market price projections?

A. **(REDACTED)**.

8. Ownership of Supply

Q. How was the ownership of California generating plants changing during this period?

A. From the inception of the PX market in 1998 through mid-1999, roughly 20,000 MW of California generating capacity had changed hands. The resulting ownership of supply in the market for 2000 was meaningfully different from what it was in 1998 and early 1999. In general, capacity had shifted from vertically integrated utilities – with offsetting load obligations to serve retail customers – to merchant generating companies with a primary interest in raising prices and revenues. Based on these incentives, and on academic analyses of the market, it was reasonable to expect that the new owners might bid the output from their plants more aggressively (i.e., at higher prices) than the previous utility owners, putting some amount of upward pressure on wholesale market prices during periods of tight supply.

9. CaISO Price Caps

Q. How are spot market prices affected by changes in wholesale market price caps?

A. Wholesale price caps can limit the extent to which spot market prices may respond to the factors that influence price.

Q. Did the CaISO price caps change prior to the record period?

A. Yes, they did. Price in the ancillary services and real time energy markets were originally capped in 1998 at $250 per MWh to address software problems. During the summer of 1998, PX spot prices shot up after the caps were lifted. It was determined that the markets were not workably competitive and that price caps should be re-introduced until the energy and ancillary services markets could be reformed. The CaISO governing board subsequently decided to raise the price caps to $750, effective September 30, 1999 pending further study of the market reforms.

Q. What were the implications of this last change for PG&E?

A. The result of the change was to increase PG&E's exposure to high spot price outcomes not only in the CaISO real-time imbalance and ancillary services markets, but also in the PX day-ahead and day-of markets. This is because the prices bid into the PX spot markets depend in part on potential prices in the real-time market.

10. NOx Emission Allowance Prices

Q. Please describe how the NO_X emission allowance market works.

A. In 1993, the South Coast Air Quality Management District ("SCAQMD") in California adopted the Regional Clean Air Incentives Market ("RECLAIM") program to reduce NOx and SO_2 emissions.[32] RECLAIM is a market-based program that requires participants to comply with facility-specific annual NOx emission levels that decrease on an annual basis until 2003, when they remain constant. RECLAIM participants include all stationary sources (including refineries, electric generating plants, and other facilities) that emit at least 4 tons per year of NOx in and around Los Angeles.[33] The total allowed emissions from participant facilities is a binding constraint, or a cap, on annual NOx emissions. Each market participant must cover its actual emissions in each program year with allowances from that year. RECLAIM trading credits ("RTCs") represent a cost of incremental operation for the thousands of generators in the area, and it is reasonable to expect such generators to include the price of RTCs in their electricity bid prices.

Q. How does the NO_X RTC market affect California electricity market prices?

A. In 2001, there were 18 electric generators representing over 10,000 MW of capacity[34] participating in the RECLAIM program. Those generators were required to obtain sufficient RTCs to cover their actual NOx emissions in each compliance year. The electric generators were allocated almost one fourth of the total emissions allowances in 1994; in 2000 their percentage of emission allocations decreased to about 14 percent.

When bidding their output into the wholesale electricity market, electric generators aim to recuperate their variable costs during the periods they operate. RECLAIM trading credits (RTCs) represent a cost of incremental operation for RECLAIM participant generators, and it is reasonable to expect such generators to include the price of RTCs in their electricity bid prices. In other words, the higher the RTC prices, the higher electricity price a RECLAIM participant generator will require in order to generate. In years of tight RTC supply,

[32] The SCAQMD also administers an SO_2 market in California.

[33] The South Coast Air Basin includes all or portions of Los Angeles, Orange, Riverside and San Bernardino Counties in California.

[34] Including a limited amount of capacity on deactivated reserve.

therefore, the electricity spot market is pushed up the supply curve to more expensive generating units, resulting in higher electricity prices.

Q. What was the outlook for the NOx allowance market heading into summer 2000?

A. In the early years of the program, there were many more RTCs available than NOx emissions of RECLAIM participants. During the late 1990s, the declining schedule of allowed NOx emissions had eliminated most of the market surplus. Exhibit DCS-8 illustrates the annual RTC supply (i.e., the total allowed emission of participant facilities) and RTC demand (i.e., the total actual emissions). This figure shows that by 1999, demand for RTC was going to equal the available supply. It was apparent in 1999 that the market, as a whole, would need to reduce NOx emissions in the immediate future. Because RTC demand was approaching the available supply, the market in the year 2000 promised to be even tighter and potentially deficient unless additional NOx emission control equipment was installed. It was also known that some of the same key outcomes (e.g., reduced hydro production, high weather-driven electricity demand) that tend to increase prices in the electricity market would also put additional pressure on the allowance supply, and could trigger significantly higher allowance prices.

11. Natural Gas Prices

Q. How are California electricity prices affected by the price of natural gas?

A. Generating plant owners will generally offer the output from their units at prices that at least equal the variable cost of production (i.e., fuel and variable O&M). In California, for example, many of the marginal generating units burn natural gas. As a result, changes in delivered natural gas prices strongly affect the market price of electricity in California. For example, an increase in the price of natural gas price from $2.00/mmBTU to $2.50/mmBTU, would cause the bid price for the South Bay gas steam plant, with an annual average heat rate of 10,000 BTU/kWh, to increase by $5/MWH to cover the fuel cost increase. History had shown natural gas prices to be uncertain, particularly on a monthly basis and it was well known that new electric generating capacity would be increasing the demand for natural gas in this country. Aside from the tightening electricity supply situation, variations in natural gas prices would represent another degree of uncertainty to summer 2000 electricity prices.

Q. What could be observed regarding gas prices?

A. Exhibit DCS-9 illustrates daily spot gas prices at Henry Hub (Louisiana) from January 1998 through April 2000. These prices were indicative of national price trends and roughly indicative of prices in southern California during this period. The exhibit shows that natural gas prices drifted significantly upward during late 1999 and early 2000. For example, prices from September 1999 through April 2000 averaged over $2.50/mmBTU, compared to prices under $2.00/mmBTU during late 1998 and early 1999. By March, prices had increased by about $1/mmBTU compared to early 1999 values.

12. Conclusions Regarding Market Fundamentals

Q. Please summarize your conclusions with respect to the outlook for California spot market prices for the record period, based on information that was available in late 1999 and early 2000?

A. An assessment of the supply/demand outlook and the other cost factors affecting the California electricity market indicates that the outlook for spot market prices for summer 2000 and beyond was higher than in recent history. It was foreseeable that spot market prices would increase, and that there was a meaningful probability of large price increases.

In addition, the potential for extreme price outcomes had increased. It was foreseeable that less favorable (but quite plausible) outcomes for several market drivers could produce much tighter conditions, and much higher spot market prices.

For these reasons, the historical California spot prices were not a good indicator of how spot prices for summer 2000 would turn out. Higher prices were more likely, and the potential summer price range included values far above historical prices.

Q. What were the implications of these higher prices for PG&E's purchasing strategy for the record period?

A. As discussed, the information available in late 1999 and early 2000 indicated that there was a meaningful probability of large spot market price increases, particularly in summer months. PG&E had a large net short position for the record period, and it was clear that failure to hedge a large fraction of that position would leave it exposed to substantial financial loss.

For illustration, in February 2000 PG&E's projections indicated an average net short position of roughly **(REDACTED)** for peak hours in summer 2000. **(REDACTED)**. For this net short position, a relatively high peak spot market price outcome of $150/MWh (comparable to the experience at Cinergy in 1998) would translate to a purchased power cost increase of about **(REDACTED)**. Exhibit DCS-10 shows this estimate.

Q. Was there a risk that BFM purchases would turn out to be more costly than spot market prices during the record period?

A. Yes. While it also possible that spot market prices during the record period would turn out lower than the BFM prices available to PG&E, the "downside" risks associated with this outcome were not, in my opinion, comparable to the "upside" risk associated with remaining short and encountering a high spot market price outcome.

Specifically, the BFM prices available in late 1999 and early 2000 for deliveries at NP-15 in summer 2000 were in the range of **(REDACTED)**. These prices were only moderately higher than actual spot market prices in summer 1998 and summer 1999, which averaged about $43/MWh and $41/MWh, respectively. As discussed earlier in my testimony, these 1998 and 1999 spot market results were achieved in conditions that featured relatively favorable hydroelectric production and regional temperatures, and did not feature the reasonably foreseeable reduction in installed capacity margins and the tightening of the SCAQMD NOx allowance market in 2000. Thus, it was unlikely that spot market prices in summer 2000 could have turned out significantly lower than actual summer 1998 and 1999 prices. And as a practical matter, spot market prices in a low market price outcome would be bounded by the variable costs of the marginal generating units in the market.

Suppose, for example, that PG&E had filled its estimated summer 2000 net short position with BFM purchases at an average price of $60/MWh and peak spot market prices in summer 2000 turned out at a very conservative level of $30/MWh. This would have represented a drop of $11/MWh or 27 percent from actual 1999 spot prices (which themselves were produced by fairly favorable supply and demand conditions), and was probably a practical low bound on the range of potential spot market prices for planning purposes. The potential above-market exposure associated with the BFM purchases in this outcome would be about $150 million, or about one third as much as the upside exposure associated with maintaining an open position. This estimate is also shown in Exhibit DCS-10. While I am not trying to be precise here, I believe that this example provides a reasonable illustration of the relative exposures.

Q. How did forward prices in the Western market for deliveries in the record period behave prior to summer 2000?

A. Exhibit DCS-11 illustrates the trend in monthly forward prices for deliveries in summer 2000, based on broker quotations for NP15. The exhibit shows actual broker quotes beginning September 1999 and extrapolated prices for July and August 1999. As noted below, **(REDACTED)**. The exhibit shows that forward prices increased somewhat from July 1999 through March 2000. Through this period, forward prices remained well below the potential high spot market outcomes suggested by experience in eastern markets.

Finally, a much more substantial forward price increase is evident between May and June 2000 – when PG&E bought **(REDACTED)** of its BFM purchases for summer 2000. By this time hot weather had been felt across most of the WSCC and hydro production had eroded, the consequences of the tight supply situation were being observed, and spot market prices had increased dramatically. The opportunity to hedge at pre-crisis market prices was gone.

Q. Do forward prices indicate the maximum spot market prices that may occur in the delivery period?

A. No, they do not. Forwards represent fixed prices at which willing sellers and buyers commit at a particular time for deliveries in a future period. As such, forward prices are an important indication of future price trends. They do not, however, represent a forecast of future spot market prices, or the maximum or minimum for future spot prices. In many cases, and particularly where the supply/demand balance is tight, spot market prices for the delivery period can turn out much higher or lower than the prices of forward trades that were made in advance.

In July 1999, PG&E was authorized to make approximately 2,000 MW of BFM purchases each month through October 2000. From that time until well into 2000, BFM prices reflected only some of the upside price risk in the California market. Had PG&E made BFM purchases for summer 2000 at that time, it would have paid prices that were only somewhat above those that had been observed in California during the previous summers, but much less than the actual spot and forward prices that had been observed in eastern markets during previous summers.

Q. Once PG&E had been given authority to make BFM purchases, what BFM prices for delivery at NP15 were available?

A. PG&E received forward price quotes by telephone prior to August 12, 1999 and electronically via e-mail after that date. However, PG&E indicates that it did not retain the telephone quotes and that its archive of the electronic quotes is not complete. For this reason, I created a schedule of forward prices for the record period that comprises actual NP15 broker quotes and, where necessary, other prices that are based on trends in the quotes.[35] Exhibit DCS-11 shows the trend in broker quotes for summer 2000 contract over time for the transaction period July 1999 through June 2000. As indicated in the exhibit, BFM purchases could have been made in the fall of 1999 at prices in the range **(REDACTED)**. BFM prices gradually increased as the summer approached, and the market observed additional signs of tight supplies. BFM prices for summer 2000 remained around **(REDACTED)** or less until late May, 2000.

Q. If PG&E had been systematically evaluating its exposure to the spot market in the second half of 1999, how should it have viewed those BFM prices?

A. The BFM prices available in the fall of 1999 for summer 2000 were moderately above the average spot prices that had been observed in the summers of 1998 and 1999. This relationship made sense because, as noted above, during those years the combination of key market drivers (i.e., hydro production, weather-driven demand, generator availability, natural gas prices, etc.) had been relatively favorable and several factors including a tightening supply/demand balance were pointing to higher prices for 2000.

Because the California electricity market had not yet seen sustained adverse combinations of the market drivers, the upside for electricity prices in California was not as well defined. Other U.S. electricity markets had, however, experienced the effects of tight supply conditions, with well-publicized results. Specifically, peak summer electricity prices in other U.S. markets had already increased several-fold during the past two years - to average well over

[35] Broker quotes for forward purchases at NP15 are a reasonable proxy for BFM prices based on a comparison of sample BFM transaction prices and the corresponding daily broker quotes.

$100/MWh. I believe that it would have been reasonable for PG&E to conclude – as ICF/Kaiser and SCE did – that there was a meaningful likelihood that California would experience summer 2000 electricity prices comparable to those that had been observed in the U.S. Midwest. In short, the BFM prices available in fall 1999 were much lower than the spot prices that PG&E would face in an unfavorable market.

Q. Were the available forward prices for delivery in non-summer months of the record period reasonable?

A. Yes, in part because they were significantly lower than for the summer months. Although the prospects of shortage conditions tend to be lower because peak demands in non-summer months tend to be lower, there was upside price exposure based on the market fundamentals discussed earlier in my testimony. Average peak energy prices at NP-15 during non-summer months in 1999 showed strong increases over 1998, with four months increasing by $10/MWh or more, and prior to 2000 the month with the highest average peak price was October 1999, a non-summer month.

VII. OTHER RISK FACTORS

Q. Was there a risk that PG&E's net short position would shrink due to additional direct access load loss?

A. **(REDACTED)**.

Q. Was PG&E also exposed to the risk that off-peak spot market prices would increase during the record?

A. Yes, it was. The off-peak period is from 10 PM to 6 AM Monday through Saturday and all 24 hours during Sunday. Market prices in off-peak hours are subject to many of the same fundamentals as the peak hours, although electricity demand tends to be lower. As a result average market prices, and the likelihood of shortage conditions, tends to be lower than in peak hours.

Looking forward to the record period, PG&E had a substantial projected net short position during the off-peak hours of about **(REDACTED)**. From the perspective of risk management, the implication of this open off-peak position was that even if PG&E were to hedge its entire peak exposure, its power costs would still be significantly exposed to spot market prices and many of the same drivers described earlier in my testimony. The open off-peak position was therefore a factor that should have weighed in favor of hedging a high portion of PG&E's peak open position, particularly in late 1999 and early 2000 when PG&E did not have authority to purchases off-peak hedges.

Q. Did PG&E hedge its off-peak requirements?

A. PG&E did not obtain authority to hedge the off-peak period until August 2000. By that time, the market had experienced not merely high on-peak prices, but sustained high off-peak prices as well. PG&E did purchase off-peak products for delivery in October through December 2000. The approximate monthly amounts were between **(REDACTED)**, representing a small fraction of the total off-peak open position.

Had PG&E hedged more of its off-peak requirements beginning August 2000, it would have achieved significant additional savings. For example, I estimate that if PG&E had made forward purchases for up to half of its off-peak open position in the fourth quarter 2000, at the same average prices for the purchases that it did make for this period, its net power costs would have been lowered by about **(REDACTED)** relative to its actual purchased power costs.

Q. Should PG&E have hedged more of its off-peak requirements?

A. By the time PG&E obtained authority to make off-peak purchases in August 2000, spot market prices for peak and off-peak deliveries had reached unprecedented levels. Off-peak market price risks (e.g., the potential for unacceptably high off-peak price outcomes) had increased, and the issue of hedging the off-peak should have been reexamined. On the other hand, forward market prices for off-peak deliveries had increased greatly as well, so that the potential opportunity costs associated with a subsequent spot market decline were greater than they had been in late 1999 and early 2000.

I have not examined the market drivers and conditions associated with the off-peak period sufficiently to conclude definitively that PG&E should have hedged more than it did for the off-peak hours in late 2000. For purposes of formulating an adjustment, I have ignored the off-peak period in its entirety. Given the potential magnitude of off-peak savings, this makes my findings regarding peak period more conservative.

Q What other cost risks was PG&E exposed to during the relevant period?

A. In addition to peak and off-peak price risk and volume risk, PG&E was exposed to several other cost risks that had the potential to increase its exposure to future spot market prices. These risks include: (i) the switching of QF suppliers to PX-based SRAC pricing; (ii) ancillary service costs;[36] and (iii) the correlation between high prices and high loads.

Q. Please explain how QFs that elected to receive energy payments based PX prices exposed PG&E to more price risk.

A. In November 1999, the Commission granted QFs a one-time option to receive energy payments based on PX market-clearing prices.[37] Prior to that decision, QF energy payments were based upon a benchmark energy price adjusted for changes over time in a gas index and any payments in excess of market were deemed recoverable as a transition cost. Because energy payments under the benchmark approach were indexed to gas, the net short understated PG&E's exposure to market volatility prior to November 1999. And providing QFs the option to switch to a PX-based SRAC pricing approach increased that exposure.

Q. Did large numbers of QFs switch to PX-based SRAC pricing?

A. Yes. After spot market prices increased during mid-2000 many QFs elected to receive PX-based SRAC payments, causing PG&E's procurement costs to increase significantly. From the period June 2000 through December 2000, energy costs for power supplied by QFs that switched to PX-based SRAC pricing were approximately $375 million more than these QFs would have received under the benchmark pricing approach.[38]

Q. Why do ancillary services costs increase PG&E's exposure to high market price outcomes?

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[36] These are services used by the ISO to ensure reliable operations and generally consist of spinning, non-spinning and replacement reserves, regulation and voltage control.

[37] Opinion regarding motion requesting approval for power exchange based pricing under Public Utility Code $390{c}, November 4, 1999.

[38] See PG&E's 10Q for period ending December 31, 2001, page 29.

A. PG&E incurs ancillary services charges from the CaISO for scheduling and delivery of energy to meet the net short. The volume of ancillary services required in any given hour is based on the energy scheduled for that hour while the price for those services is based on the day-ahead and hour-ahead bids that the CaISO receives in its ancillary services auction process. However, because energy prices and ancillary services prices tend to be correlated, the requirement to purchase both energy and ancillary services to cover the net short meant that PG&E's exposure to high spot market price outcomes was greater than it would have been if its obligation was limited to purchasing energy.

Q. The correlation between high prices and high loads has been explained already above. Please explain why this risk is not captured in the risk of covering the net short with spot market purchases.

A. As explained, PG&E's strategy was to purchase BFM hedges up to certain percentage of its peak net short, which was calculated on an hourly basis and then averaged over the peak hours in the delivery month or quarter. One result of this averaging process was to leave PG&E exposed to hourly peaks in the net short, which is correlated with PG&E's hourly peak loads and hence high prices. Thus, even a hedging strategy designed to cover 100 percent of the net short would leave PG&E purchasing spot market energy during relatively high-cost hours, and would not eliminate all of the uncertainty in the cost of procuring energy. To reduce the uncertainty further, PG&E would have to purchase superpeak hedges or increase the hedge target.

Q. Was PG&E aware of these cost risks, and their relevance to hedging, before it established its 50 percent hedging strategy?

A. Yes, I believe that the cost risks associated with ancillary services and high loads were understood by PG&E. As regards QF pricing, PG&E was aware in November 1999 that all QF suppliers could exercise a one-time option to receive energy payments based on PX market-clearing prices. In summary, it appears that

PG&E understood that these factors increased its financial exposure to spot market price outcomes, relative to the exposure that its net short position would indicate.

Q. Are there other indications that PG&E was aware of these risks, but failed to reflect them in its hedge targets?

A. Yes, in July 2000, PG&E management proposed to the Utility Risk Management Committee ("URMC") hedge targets in MW that reflected 50 percent of estimated net short positions that had been increased to account for the additional cost risks. Those hedge targets were not adopted by the URMC.

VIII. ALTERNATIVE HEDGING STRATEGIES

Q. Your testimony suggests that PG&E's BFM hedging strategy should have been informed by a market fundamentals analysis conducted in 1999 and an evaluation of cost risks described above. Before you describe that strategy and summarize its likely results, please explain the BFM purchases that PG&E actually made for peak hours during the record period.

A. During the period July 1999 through January 2000, PG&E made no BFM purchases for delivery in any portion of the record period. Beginning **(REDACTED)**, PG&E began to buy steadily for deliveries in Summer 2000 at a rate of **(REDACTED)** per month. In May 2000, as market prices were increasing, **(REDACTED)**. After receiving authority to make bilateral purchases in August 2000, PG&E continued to make significant BFM purchases along with **(REDACTED)** for delivery in October through December. Most of the forward purchases that PG&E made for delivery in the fourth quarter – amounting to at least **(REDACTED)** each month - were made in **(REDACTED)**.

Exhibit DCS-13 provides a summary of PG&E's on peak[39] forward purchases (including both BFM and bilateral purchases) for delivery through December 2000. The exhibit shows the purchases in MWs, MWhs, dollars and dollars per MWh by purchase month and delivery month. Because the bulk of PG&E's purchases were made after **(REDACTED)**, at prices well above the BFM prices in earlier months, it is clear that PG&E's delay in beginning its BFM purchases was costly.

Q. How do PG&E's BFM and bilateral purchases for the record period compare to its hedge target?

A. PG&E's actual hedges averaged just over **(REDACTED)** of the projected net short over the record period. Exhibit DCS-14 shows how PG&E performed relative to target and to net short on a monthly basis.

Q. Did PG&E's BFM and bilateral purchases effectively hedge its net short requirements against the large increase in spot market prices that occurred in mid-2000?

A. No. As noted above, PG&E only purchased a limited portion of its net short requirements on a forward basis. Just as important, Exhibit DCS-13 shows that only a limited portion of PG&E's forward purchases were made between July 1999 (when it received BFM purchasing authority) and May 2000. Specifically, for the period July 2000 through December 2000, **(REDACTED)** of PG&E's forward purchases were made in **(REDACTED)** or later, after spot and forward market prices had increased substantially.

Q. Based on the available information, what do you believe PG&E should have done differently with respect to the amount and timing of its forward purchases during the record period?

[39] Most of PG&E's forward purchases were specifically for delivery in peak hours. A limited amount of the peak purchases depicted in this summary were round-the-clock purchases that also provided deliveries during offpeak hours.

A. First, PG&E should have begun purchasing promptly. PG&E had a large open position, and I believe that it should have begun utilizing its initial BFM purchasing authority to reduce that open position during summer 1999. The available information about the wholesale market indicated a meaningful likelihood of large spot market increases for this period, and the prevailing BFM prices were not excessive in view of these potential outcomes and the limited history of spot market prices.

Second, PG&E should have utilized its initial BFM purchasing authority by early 2000. This pace would still leave a significant remaining open position in each month, and enough time to fill it with the additional BFM purchasing authority that PG&E requested in January 2000.

Third, once the Commission authorized (in early March 2000) PG&E to purchase for months after October 2000, and up to its net short requirements in all months through the end of its rate freeze, PG&E should have made forward purchases[40] at a pace sufficient to fill most of its estimated net short requirements by the month of delivery.

Q. Have you developed a specific alternative purchasing strategy?

A. Yes, I believe that the following alternative set of purchases for peak hours during the record period would have been reasonable under the circumstances:

- Beginning in September 1999, purchase monthly or quarterly BFM products for delivery in July through October 2000, at an average rate of about 350 MW per month. This pace would fully utilize PG&E's initial BFM purchasing authority by the end of 1999;
- Beginning in March 2000, purchase additional BFM monthly or quarterly products at a rate of about 400 MW per month for each month of the delivery

[40] PG&E's forward purchases would include bilateral purchases made after August 2000, when PG&E received authorization to make such purchases.

period. This pace would fill about 80 percent of each month's forecasted net short position, shortly before the delivery month.

A graphical comparison of our alternate hedge strategy with PG&E's strategy and the net short is shown in Exhibit DCS-15. Exhibit DCS-16 (2 pages) illustrates the purchase volumes and estimated expenditures associated with this alternative purchasing strategy on a monthly basis.

Q. Why was it appropriate for PG&E to purchase most or all of its estimated net short position on a forward basis?

A. First, PG&E had a large open position during peak hours. As I have illustrated, remaining open would greatly increase PG&E's purchased power costs in the event of a high spot market price outcome. The savings opportunities that PG&E would forego by purchasing forward (i.e., the ability to benefit from low spot market price outcomes) were limited.

Second, the forward prices that PG&E would have had to pay in the BFM appear reasonable based on a review of the fundamentals at the time. They reflected some premium over recent historical spot prices, which was not surprising based on the hydro and weather conditions that pertained in 1998 and 1999 and the observed and anticipated changes in market drivers (e.g., demand growth, tightening NOx market, generation ownership change) that were pointing to the potential for increased prices. It is also notable relevant that although average PX spot prices in 1998 and 1999 had not been excessive, those prices had exhibited significant daily and monthly price volatility and year-over-year price increases in 1999 relative to 1998. At the same time, the available BFM prices were well below those that PG&E could have expected to pay in a high spot market price outcome.

Third, PG&E's effective exposure to spot market prices was greater than would be indicated by a "base case" estimate of its average net short position. In particular, PG&E had a substantial estimated open position across the record period, and (until August 2000) no authority to hedge that position. Even if

PG&E hedged its entire peak exposure, the offpeak exposure would leave its power costs significantly exposed to spot market prices and many of the same drivers described earlier in my testimony. Similarly, the price of PG&E's QF purchases depended to some extent on natural gas prices and there was some risk that if wholesale market prices increased substantially, PG&E's financial exposure in 2000 would be aggravated by QFs utilizing their option to switch to spot-based pricing. Finally, PG&E's open position was weighted somewhat toward peak hours and days that would tend to feature the highest market prices and volatility, so that hedging the full average open position could leave some residual market price exposure.

Collectively, these factors indicated that it would have been reasonable for PG&E to hedge, over time, all of its forecasted peak net short position for the record period. That is, it would have been appropriate for PG&E to lock in its needed supplies over time at the BFM prices that were available during this period, rather than leaving much of its costs to be determined in a volatile spot market.

Q. Why have you presented a set of alternative purchases that ultimately fills 80 percent of the estimated net short, rather than all of it?

A. The primary rationale for limiting the alternative purchases to 80 percent of the net short is my intent to produce a conservative result. I also wanted to allow for the potential that although the migration of customers to alternative suppliers appeared to have slowed or stopped by late 1999 and early 2000, some additional migration (and associated reduction in PG&E's net short requirements) was possible in the future.

Q. Have you estimated how your recommended alternative strategy would have affected PG&E's purchased power costs during the Record Period?

A. Yes, I estimate that the alternative strategy would have reduced PG&E's purchased power costs during the period July 2000 through December 2000 by

$434 million, relative to the actual costs that PG&E incurred. Exhibit DCS-17 contains the details of this calculation.

Q. Please summarize how you estimated the savings associated with the alternate procurement strategy.

A. First, I estimated what PG&E would have had to pay to purchase the peak forward deliveries shown in Exhibit DCS-16. Because PG&E did not maintain a complete record of BFM prices at NP-15 during the period in question, I approximated the BFM prices using broker price quotes provided by PG&E in discovery. In general, I estimated the price of BFM purchases made in each month using a quote from the middle of the month. For months in which mid-month prices were not available for deliveries in all months of the record period, I made reasonable approximations using a combination of other monthly and quarterly forward price quotes. Exhibit DCS-16 shows the resulting monthly prices, and their application to monthly BFM volumes to obtain the estimated cost of BFM purchases under the alternate strategy.

Second, I estimated the cost of PG&E's actual forward purchases during peak hours; this calculation is summarized in Exhibit DCS-13.

Finally, I estimated the savings achieved by the two hedging strategies (PG&E's actual purchases, and my alternate strategy), by comparing the cost of the forward purchases to the cost of purchasing the same quantities at spot market prices, based on daily onpeak index prices for NP-15 from Power Markets Week.

The difference between the two savings estimates represents the incremental savings that PG&E could have achieved by implementing the alternate strategy. This analysis produced incremental savings of about $434 million for the period July 2000 through December 2000. Exhibit DCS-17 shows these results.

Q. Would the precise set of alternative purchases that you have outlined have been the only prudent course of action for PG&E?

A. No, a number of potential combinations of purchases could have been reasonable, but a prudent strategy would have contained the key features (i.e., begin purchasing promptly, utilize the initial BFM purchasing authority by early 2000, and utilize most or all of the additional purchasing authority) that I have described. Within these parameters, small variations in the amounts and timing of monthly purchases would not strongly affect the estimated savings.

Q. Did other market participants take the steps that you believe PG&E should have taken?

A. Yes. It is instructive to examine the case of SCE, an electric utility which also had the obligation to procure power for those of its customers that had not chosen an alternative generation supplier.

Resolution E-3618 provided SCE the same authority to make BFM purchases as that provided to PG&E. A review of public information and confidential material from Investigation No. I.00-08-002, indicates that SCE took the steps that I have recommended. Each of the following aspects of SCE's procurement approach present a clear contrast to PG&E:

- SCE had a BFM hedging strategy for summer 2000 in place before 2000.
- SCE analyzed its BFM purchase opportunities from the perspective of lowering its exposure to variance in spot prices, so long as BFM prices were within a reasonable range of SCE's current base expectation for spot prices.
- In developing volume and price limits for its BFM purchases, SCE analyzed the outlook for California spot market prices for a base case approach, and for alternative scenarios. SCE updated its analysis over time, reflecting changes in market conditions and changes in its own market price outlook.
- SCE recognized that California spot market prices for summer 2000 were likely to turn out higher, and might turn out several times higher,

> than the historical spot prices from 1998 and 1999. SCE's high price scenario developed in March 2000 for summer 2000 featured monthly average peak spot prices between **(redacted)** and **(redacted)**. SCE's low price scenario for summer 2000 **(redacted)**.[41]

The data provided in Investigation No. I.00-08-002 shows that SCE bought on average about **(redacted)** per month in the BFM for delivery summer 2000. By analyzing the PX's records of transactions in the BFM for delivery at SP15 during the summer months, I estimate that SCE purchased on average in 1999 at least **(redacted)** per month and possibly **(redacted)** for delivery summer 2000. These quantities compare to zero MW purchased by PG&E in 1999 for the same delivery period. In total, SCE purchased on average approximately **(redacted)** per month of BFM contracts for delivery in the third quarter and **(redacted)** for delivery in the fourth.

The point here is that SCE appears to have taken a more active approach to risk management. SCE investigated the potential range of market price outcomes, identified its exposure to those outcomes, and took relatively prompt steps to limit that exposure. At a minimum, this demonstrates that SCE conducted the development and execution of hedging in a far different way than PG&E. While it is possible that SCE should have done more than it did, that would require an analysis far beyond the scope of my testimony.

Q. PG&E's testimony states at page 2-5 that "A major factor that led PG&E to hedge below the regulatory limit was its concern that the Commission might disallow BFM costs incurred for contracts delivered after the end of the rate freeze." Please assess that concern.

A. In order for PG&E to show that was a reasonable affirmative defense, PG&E would have to specify the probability and consequences of this concern, and place it in the context of the other factors affecting its purchasing strategy. PG&E has not done so. In particular, I have not seen in PG&E's presentation anything

[41] The details are contained in Investigation No. I.00-08-002, Confidential Data Request EMI-ORA-1 (dated 10/26/00), Response 7.

indicating that, in the 1999 and early 2000 period under consideration, the Company actually expected its rate freeze period to be over before the BFM contracts would be delivered (October 2000, at the latest). Given this, it is not clear why post-freeze cost recovery concerns should have affected PG&E's hedging strategy for deliveries in Summer 2000.

Q. What sort of clarification regarding BFM cost recovery did PG&E seek in January 2000?

A. PG&E filed Advice Letter 1960-E on January 19, 2000. In that advice letter, PG&E states:

> "The need to continue hedging price risk for bundled-service customers remains. However, given the uncertain end-date of PG&E's rate freeze, PG&E's ability to recover its BFM costs is unclear, particularly in the event the end date of the rate freeze precedes the delivery date or energy purchased before that date. This uncertainty makes it very difficult for PG&E to continue hedging price risk using the BFM.
>
> If D 99-10-057 is interpreted in such a way that costs and benefits of block forward transactions made today can not be recovered after the rate freeze, then it is impossible to continue hedging the price risk of energy purchases for any date that may turn out to be post-rate freeze. PG&E's customers will remain fully exposed to prices in the spot markets.
>
> If costs and benefits of the BFM are viewed as being incurred on the date of energy delivery, then cost recovery is possible under the PTER Phase 1 decision. However, these transactions might still be subject to reasonableness review or some other type of oversight, not yet determined."

Q. Could you comment on the first scenario?

A. PG&E does not explain why it would have been impossible to continue hedging, how D 99-10-057 could be interpreted to block any form of cost recovery, and (even if such an interpretation were possible) what it would mean for the Commission to do so.

To evaluate PG&E's claims on this point, it is useful to distinguish the commitment to a forward purchase from the delivery. Forward transactions represent agreements to purchase and deliver power at a delivery date some time in the future; payment and settlement is typically made at or after the delivery date. In the context of a block forward purchase, therefore, a logical interpretation of cost "incurrence" would reflect the date of delivery, not an earlier date at which the commitment was made. On March 16, 2000, in a decision noted earlier, the Commission made clear that the cost of a forward purchase is in fact "incurred" at the time of delivery.

Further, PG&E puts forth no rationale for how the total denial of cost recovery for BFM purchases would be a possible outcome. It seems to me that denying the possibility of any recovery for a purchased power transaction that has a demonstrable market value appears to go beyond the bounds of reasonable ratemaking. It seems logical that at most, PG&E's cost recovery exposure with respect to a BFM purchase would be the positive difference (if any) between the BFM contract price and prevailing spot market prices at the time of delivery.

Q. Isn't it true that the ratemaking treatment of BFM purchases was uncertain during at least part of the period that you assert PG&E should have been purchasing in the BFM?

A. Yes. The Commission had indicated that it would review PX purchases delivered after the rate freeze unless it decided on some other form of ratemaking, and I am not aware that the Commission had yet spelled out the details of how BFM and other purchases would be evaluated. But this uncertainty is not a reason to refrain from proper hedging practices. The prospect of reasonableness review is hardly a harbinger of disallowance; the ultimate defense against potential disallowances is sound decision making. A well developed and well documented risk management strategy would have substantially addressed the regulatory risk to PG&E, while failure to effectively hedge risk would expose it to regulatory risk.

It is also relevant that the potential dollar magnitude of the cost exposure to PG&E's shareholders and customers associated with hedging should have been viewed as less than that associated with an unhedged position. Given the market fundamentals described earlier, indicating the potential for large market price increases, the potential exposure of a large unhedged load in a high spot market outcome was very substantial and much larger than that associated with holding forward contracts after the end of the rate freeze period in a low spot market outcome.

In this case, PG&E's focus on potential regulatory risks appears to have obscured its view of the risks that were right in front of it: the risks of high prices. Even if PG&E did perceive regulatory risk, it needed to balance that risk against the clear and present market risks it faced.

Q. PG&E claims (see Response ORA 020-08) that one of the reasons for its limited hedging was limited supply and liquidity in the BFM market. Is this argument convincing?

A. No, PG&E has not shown that a lack of liquidity[42] materially hampered its participation in the BFM market. While PG&E does not precisely elaborate this concern, it appears to be claiming that the number of market participants or the frequency of available trades in the BFM was insufficient to support its hedging activities. This claim is questionable for several reasons.

First, in evaluating PG&E's claims of thin trading and low liquidity at NP-15, it is important to recognize that as the largest load serving entity in northern California, PG&E was the largest natural buyer at that location. PG&E itself has stated that it was essentially the only buyer. In this context it would not be surprising that during a period when PG&E had not yet begun to purchase, BFM trading volume at NP-15 would be low. Low volumes would appear to reflect PG&E's lack of interest in trading at that time and later its "buy and hold"

[42] In the context of a commodity market, I understand a high liquidity to refer to markets in which a large number of participants trade frequently.

approach to hedging, rather than an unwillingness of sellers to participate in the market.

Second, there was significant trading volume during late 1999 and early 2000 at SP-15, the other major BFM trading location. Exhibit DCS-18 illustrates the total monthly BFM trade volumes for July 2000 deliveries at SP-15, including monthly and quarterly products. The exhibit shows that the BFM trading began in substantial volumes in October, within the first several months after the IOUs received authority to purchase, and continued through early 2000. The cumulative trade volume for this delivery period was about 4,000 MW. This activity indicated that sellers were willing to participate in the BFM if buyers were present.

Finally, when PG&E chose to buy in the BFM for deliveries in the record period, it was able to do so. PG&E made purchases of **(REDACTED)** per month from **(REDACTED)**, and purchased greater amounts during some later months. While PG&E may not have encountered in the BFM the same degree of liquidity that it would have found in the bilateral market, PG&E has not shown that the pace and amount of its BFM purchases were limited materially by anything other than its own strategy.

Q. Does your alternate strategy have benefits other than the reduction in power purchase costs?

A. Yes. Had this strategy been implemented, a significant fraction of the energy needed to supply the net short during the record period would have been under contract by the end of May 2000 at prices that were fixed and substantially below the levels that spot and forward prices ultimately reached. While PG&E would still have been exposed during superpeak and off-peak hours, it would have been substantially more hedged in the second half of the record period (i.e., January 2001 through June 2001) than PG&E actually was and therefore would have been better positioned to mitigate the price risk in 2001.

IX. CONCLUSION

Q. Please describe your conclusions.

A. First, PG&E did not pursue a reasonable BFM purchase strategy. Despite working with the PX to develop a market for block-forward contracts, and seeking and receiving Commission authority to participate in that market up to its net short position, PG&E did not develop a BFM strategy for the record period that made proper use of that authority. Specifically, PG&E did not begin to mitigate its summer 2000 price risk until **(REDACTED)**, by which time BFM prices had risen above 1999 levels. Further, by adopting a 50 percent hedge strategy, PG&E made very little use of the expanded hedging authority provided in Resolution E-3658.

Second, PG&E's failure to develop a reasonable BFM strategy is attributable in part to the fact that it did not act on market information it possessed that provided ample evidence of the risk and elevated probability of price risk. Had PG&E made proper use of that information in the second half of 1999, I believe it would have concluded that the outlook for spot market prices was higher than in recent history and that the potential for extreme price outcomes had increased. Based on this conclusion, it would have been reasonable for PG&E to develop and implement a much more aggressive hedging strategy than it actually did.

Third, PG&E's arguments as to why it chose to hedge substantially below the limits established by the Commission are not convincing. PG&E had a large net short position for the record period. In late 1999 and early 2000, when PG&E had authorization to make BFM purchases, the available information about the Western market indicated that spot market prices were likely to increase in 2000, and that there was a meaningful probability of large increases. It was a logical time for power buyers to be hedging, and particularly for PG&E which faced a fixed retail rate cap.

Fourth, a review of PG&E's power purchases for the record period shows that once the Commission authorized PG&E to make BFM purchase to hedge the cost of its net short position, PG&E did not make any BFM purchases until **(REDACTED)**. As a result, only a limited fraction of PG&E's net short position was purchased before **(REDACTED)**, and protected against the large market price increases that followed. Most of PG&E's purchases for delivery in the record period were made in **(REDACTED)** or later, after market prices had increased greatly. In short, while PG&E had access to tools (i.e., BFM purchases) that would have provided a great deal of protection against potential market price increases, it chose not to fully utilize those tools and found itself largely exposed to the Western power crisis that followed. Based on the above, I believe that PG&E did not prudently manage its power purchases for the record period.

Based on the information available at the time, I believe that PG&E should have begun to hedge its exposure to spot market prices earlier than it did and purchased a larger fraction of its net short requirements on a forward basis. Specifically, I believe that it would have been appropriate for PG&E to immediately begin to utilize the BFM purchasing authority of approximately 2,000 MW that the Commission granted it in July 1999. After the Commission increased PG&E's BFM purchasing limits (to the full net short position) in March 2000, I believe that it would have been appropriate for PG&E to utilize most or all of that authority in a sequential fashion over the subsequent months. Had PG&E implemented such a strategy, it would have: (i) reduced its power purchase costs during the period July through December 2000 by $434 million; and (ii) left itself with a portfolio of hedge contracts that had the potential to significantly reduce its financial risk over the second half of the record period.

Finally, PG&E's assertion that the Commission did not eliminate ambiguity over cost recovery for BFM purchases until June 8, 2000 is not convincing. Even if this was the case, and the regulatory treatment of BFM purchases was not fully resolved, PG&E would not have been justified in leaving its net short position in the record period largely unhedged.

Q. In light of the above conclusions, what actions do you recommend?

A. As noted above, ALJ Barnett's December 19, 2001 ruling identified the issues in the proceeding as the reasonableness of: (i) PG&E's entries to TCBA; and (ii) PG&E's procurement practices. For the reasons explained above, I recommend that the Commission issue an order that: (i) finds PG&E imprudent for not pursuing a reasonable BFM purchase strategy; and (ii) directs PG&E to debit $434 million from its entries to the Transition Cost Balancing Account in accordance with the alternate hedging strategy described above.

Q. Does this conclude your testimony?

A. Yes, it does.